

**STATE OF VERMONT**  
**BEFORE THE PUBLIC SERVICE BOARD**

<b>Tariff filing of Central Vermont Public Service</b>	)	
<b>Corporation requesting a 7.6% rate increase</b>	)	Docket No. 6460
<b><u>to take effect December 24, 2000</u></b>	<b>)</b>	

<b>Tariff filing of Central Vermont Public Service</b>	)	
<b>Corporation Requesting a 12.9% rate increase</b>	)	Docket No. 6120
<b><u>to take effect July 27, 1998</u></b>	<b>)</b>	

**DIRECT TESTIMONY OF**  
**PAUL CHERNICK**  
**ON BEHALF OF**  
**THE VERMONT DEPARTMENT OF PUBLIC SERVICE**

Resource Insight, Inc.

**MARCH 9, 2001**

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1   **I.   Identification and Qualifications**

2   **Q:   State your name, occupation and business address.**

3   A:   I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347  
4       Broadway, Cambridge, Massachusetts 02139.

5   **Q:   Summarize your professional education and experience.**

6   A:   I received an SB degree from the Massachusetts Institute of Technology in  
7       June, 1974 from the Civil Engineering Department, and an SM degree from  
8       the Massachusetts Institute of Technology in February, 1978 in technology  
9       and policy. I have been elected to membership in the civil engineering  
10      honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi,  
11      and to associate membership in the research honorary society Sigma Xi.

12       I was a utility analyst for the Massachusetts Attorney General for more  
13      than three years, and was involved in numerous aspects of utility rate design,  
14      costing, load forecasting, and the evaluation of power supply options. Since  
15      1981, I have been a consultant in utility regulation and planning, first as a  
16      research associate at Analysis and Inference, after 1986 as president of PLC,  
17      Inc., and in my current position at Resource Insight. In these capacities, I  
18      have advised a variety of clients on utility matters. My work has considered,  
19      among other things, the cost-effectiveness of prospective new generation  
20      plants and transmission lines; retrospective review of generation planning  
21      decisions; ratemaking for plant under construction; ratemaking for excess  
22      and/or uneconomical plant entering service; conservation program design;  
23      cost recovery for utility efficiency programs; and the valuation of environ-

1        mental externalities from energy production and use. My resume is appended  
2        to this testimony as Exhibit DPS-PLC-1.

3        **Q: Have you testified previously in utility proceedings?**

4        A: Yes. I have testified approximately one hundred and eighty times on utility  
5        issues before various regulatory, legislative, and judicial bodies, including  
6        utility regulators in twenty-five states, New Orleans, the District of  
7        Columbia, and Ontario; the Federal Energy Regulatory Commission; the  
8        Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory  
9        Commission; and various siting and environmental regulators. A detailed list  
10       of my previous testimony is contained in my resume.

11       **Q: Have you testified previously on utility resource planning?**

12       A: Yes. I have testified on many utility-resource-planning issues, including  
13       generation, transmission, and DSM planning, in many jurisdictions in the  
14       United States and Canada. My resume details this experience.

15       **Q: Have you testified previously before the Board?**

16       A: Yes. I testified in  
17       • Docket No. 4936, on Millstone 3;  
18       • Docket No. 5270 on DSM cost-benefit test, pre-approval, cost recovery,  
19       incentives, and related issues;  
20       • Docket No. 5330, on the conflict between the HQ purchase and DSM;  
21       • Docket No. 5491, on the need for HQ power and the costs of alternative  
22       purchases;  
23       • Docket No. 5686, on the avoided costs and water-heater load-control  
24       programs of Central Vermont Public Service (CVPS or Central Vermont);  
25       • Docket No. 5724, on CVPS avoided costs;

- 1 • Docket No. 5835, on design of CVPS load-management rates;
- 2 • Docket No. 5980, on electric-industry restructuring and avoided costs;
- 3 • Docket No. 5983, on the prudence of GMP's decisions regarding the
- 4 HQ contract, avoided costs, and distributed utility planning;
- 5 • Docket No. 6018, on the prudence of CVPS's decisions regarding the
- 6 HQ contract, avoided costs, and distributed utility planning;
- 7 • Docket No. 6107, on the prudence of GMP's decisions regarding the
- 8 HQ contract and distributed utility planning.

9 **Q: Have you been involved in other aspects of utility planning and**  
10 **regulation in Vermont?**

11 A: Yes. My other activities have included

- 12 • participation in the CVPS and Vermont Gas DSM collaboratives;
- 13 • preparation of testimony on the avoided costs of Green Mountain Power
- 14 (GMP) in Docket No. 5780, not presented due to settlement of the case;
- 15 • assisting the Department of Public Service (DPS or the Department) in
- 16 the power-supply negotiations of the externalities investigation;
- 17 • providing consulting support to the Vermont Senate on stranded costs
- 18 and Vermont Yankee economics;
- 19 • assisting the Burlington Electric Department on distributed utility
- 20 planning;
- 21 • assisting the Department and preparing draft testimony in Docket No.
- 22 6120, the previous Central Vermont rate proceeding;
- 23 • assisting the Department in the statewide collaborative on Distributed
- 24 Utility Planning.

25 **Q: Are you the author of any publications on utility planning and rate-**  
26 **making issues?**

1 A: Yes. I am the author of a number of publications on rate design, cost alloca-  
2 tion, power-plant cost recovery, conservation-program design and cost-  
3 benefit analysis, and other ratemaking issues. These publications are listed in  
4 my resume.

## 5 II. Introduction

6 **Q: What is the purpose of this testimony?**

7 A: I address three topics related to Central Vermont's purchases of power under  
8 Schedules B and C of the Vermont Joint Owners' (VJO) contract with Hydro  
9 Québec (HQ), which I will refer to as the HQ-VJO contract or the HQ  
10 contract.

- 11 • The types of resources that Central Vermont would have acquired had it  
12 canceled the HQ-VJO contract.
- 13 • The adequacy and effectiveness of Central Vermont's efforts to mitigate  
14 the costs of the HQ-VJO contract.
- 15 • The excess cost of the HQ-VJO contract, compared to the costs of  
16 prudent resources, in the rate years for Docket No. 6120 (calendar  
17 1999) and for Docket No. 6460 (July 1, 2001 through June 30, 2002).

18 The chronology of major events related to these purchases are described  
19 in the Board's order in Docket No. 5701 and 5724.<sup>1</sup> The Company's  
20 purchases from HQ under this contract are roughly \$50 million annually, out  
21 of \$290 million of total revenue. The Company expects to spend more than a  
22 billion dollars under this contract during 1998–2015.

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<sup>1</sup>I use these docket numbers interchangeably in this testimony.

1    **A:   *Estimating the Damages due to the Company's Imprudence***

2    **Q:   What is the normal process for computing the costs incurred due to an**  
3    **imprudent utility action or decision?**

4    A:   The general process consists of the following three findings:

- 5       •   The finding that a particular decision was imprudent.
- 6       •   The identification of the actions the utility would likely have taken, if it
- 7           had avoided the imprudent action, and then acted prudently.
- 8       •   The determination of the cost of the likely prudent course of action.

9           As I discuss below, the Board has already found Central Vermont's  
10   purchase of power under the HQ-VJO contract to be imprudent, and further  
11   consideration of that issue has been precluded by the Vermont Supreme  
12   Court.

13   **Q:   Please describe the process of identifying the subsequent actions the**  
14   **utility would likely have taken, if it had avoided the imprudent action.**

15   A:   This task primarily involves positive or predictive analysis, rather than a  
16   normative analysis. While the original prudence analysis considers what the  
17   utility *should* have done, the identification of subsequent actions primarily  
18   concerns what the utility *would* have done, had it avoided the imprudent  
19   action.

20           Since the purpose is to project the utility's decisions in a situation that  
21   did not arise, the subsequent-action analysis relies primarily on the utility's  
22   standard procedures, adjusted as necessary to reflect the requirement of  
23   prudent utility management with due regard for the utility's obligation to  
24   ratepayers. Thus, the analyses should be based on the information the utility  
25   possessed, as well as any information it should have known but failed to  
26   obtain. The subsequent actions should be projected from the utility's normal



1 evaluation, adjusted only as necessary to be consistent with prudent manage-  
2 ment and the utility's obligation to ratepayers. Specific directives from regu-  
3 lators may establish some assumptions and evaluation methods. Adjustments  
4 to the utility's normal decision-making criteria are justified only where those  
5 criteria were unreasonable, selected imprudently from the perspective of  
6 ratepayers, or would have led to decisions that would not have obtained  
7 required approvals from regulators.

8 **Q: Can analysis determine exactly what the utility would have done in the**  
9 **past, had it not taken the imprudent action?**

10 A: No. By their very nature, these historical "what-if" exercises are inexact. The  
11 regulators will never be able to know exactly what result the utility would  
12 have received, had it bargained hard with potential suppliers. In complicated  
13 processes, including utility supply planning, the outcome can be determined  
14 by any number of factors, including the order in which parties communicate  
15 with one another, their perceptions of one another's bargaining position, the  
16 actual and perceived influence of third parties (such as regulators) and the  
17 timing of analyses and communications.

18 **Q: How should regulators deal with these uncertainties?**

19 A: That depends to some extent on the range of the uncertainties. In some cases,  
20 a single outcome can be identified as being representative, and used for  
21 subsequent analysis. In other cases, regulators should examine the range of  
22 likely outcomes, and evaluate the damages for a number of those outcomes.

23 The actions in the same time frame of other, similarly situated, utilities  
24 that avoided the imprudent action may provide a guide to the likely actions  
25 of the imprudent utility. Using a range of prudent behaviors from other

1 utilities avoids potential problems of dealing with vast numbers of possible  
2 actions, as well as the pitfall of assuming a perfect outcome.

3 In no event should regulators allow the utility to benefit from un-  
4 certainties created by the utility's own imprudence. Options that the utility  
5 imprudently failed to explore should not be eliminated from the analysis.

6 **Q: Please describe the determination of the cost of imprudence.**

7 A: The cost of imprudence is the difference between the cost of the actual action  
8 and the cost of the actions the utility would have taken had it avoided the im-  
9 prudent action.

10 This cost may be greater or less than the differential that would have  
11 been estimated at the time of the imprudent action. For power-supply  
12 decisions, the costs of the alternatives today may differ from previous  
13 forecasts due to changes in fuel prices, costs of capital, and other  
14 determinants, and due to changes in contractual arrangements (such as the  
15 retirement of units that would have served unit contracts). Hence, the costs of  
16 imprudence must be determined at the conditions that actually occurred,  
17 rather than those anticipated years earlier.

18 Even actions that were obviously imprudent may have no current cost  
19 consequences. For example, a utility that signs an exorbitantly expensive  
20 contract for power from a new resource that is never completed, and is  
21 subsequently able to obtain replacement power at a cost comparable to that  
22 of the prudent alternatives to the original contract, may incur no extra cost.  
23 No cost-based prudence disallowance would be appropriate in such a case.<sup>2</sup>

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<sup>2</sup>Nonetheless, the regulator might well decide to reflect the utility's poor planning process in some other manner, such as reducing its allowed return.

1           The cost consequences of imprudence may vary over time; an impru-  
2           dent action may increase costs dramatically for some years, but actually  
3           decrease costs in other years. The disallowance for excess costs in the short  
4           term should not exceed the total excess cost over time. It is therefore  
5           appropriate to look ahead and determine whether the consequences are likely  
6           to reverse in the future.

7    ***B. Background of this Proceeding***

8    **Q: Please describe the regulatory background of the HQ-VJO contract.**

9    A: In October 1990, in Docket No. 5330, the Board approved the overall HQ-  
10   VJO purchase. The Order in Docket 5330 also accepted that CVPS was not  
11   purchasing more HQ power than its load requirements.

12           In early 1991, CVPS filed a rate case, Docket No. 5491, in which CVPS  
13   disclosed new power-supply offers it had received from Northeast Utilities  
14   (NU), and its analyses of those contracts. The cost-effectiveness of the HQ-  
15   VO became an issue in that case, including testimony that I filed on July 19,  
16   1991. At that time, the VJO had until November 30, 1991 to decide whether  
17   to back out of the contract, or to be locked into it.

18           On August 28, 1991, the VJO voted in a conference call (scheduled by  
19   fax the day before) to waive its rights to terminate the contract and hence  
20   locked the member utilities into the contract. Most subsequent litigation  
21   regarding the HQ-VJO contract has focussed on this “lock-in” decision.

22           In Docket No. 5701, CVPS’s 1994 rate case, the Board found that CVPS  
23   management had erred in inadequately analyzing alternatives prior to the  
24   lock-in and in inadequately pursuing reduction in its HQ entitlements after

1 the lock-in. (Order at 111–112, 118–119). The Board reduced CVPS’s allowed  
2 rate of return by 75 basis points.

3 In June 1997, Green Mountain Power (GMP) filed for a rate increase,  
4 Docket No. 5983, related in large part to the rising costs of the HQ-VJO  
5 purchase. The Board found that Green Mountain Power had been imprudent  
6 in locking into the HQ-VJO contract, and disallowed 20% of GMP’s HQ-  
7 VJO contract costs in the rate year, net of the benefits of sellbacks, which  
8 brought the net prudence disallowance down to about 4% of GMP’s costs.

9 In September 1997, the Company filed for a rate increase. In that  
10 proceeding, Docket No. 6018, I filed testimony on February 11, 1998 re-  
11 garding CVPS’s imprudence in its planning for the HQ-VJO contract. CVPS  
12 moved to strike the Department’s testimony on the prudence and used-and-  
13 useful status of the HQ-VJO contract, and appealed the denial of that motion.  
14 Docket No. 6018 has been suspended since that appeal. On February 9, 2001,  
15 the Vermont Supreme Court ruled on that appeal and found that the Board’s  
16 determination of imprudence in the lock-in is final and not subject to further  
17 litigation, but that the size of future disallowances remains open.

18 In July 1998, CVPS filed another rate case, Docket No. 6120, in which it  
19 accepted a temporary disallowance for its HQ-VJO costs modeled on the  
20 order in Docket No. 5983, pending resolution of its appeal in Docket No.  
21 6018. That docket has been consolidated into the current proceeding. As a  
22 result, this case must consider the costs of the HQ-VJO contract in both the  
23 rate years for Docket-No. 6120 (1999) and Docket No. 6460 (2001/02).

24 Green Mountain Power filed another rate case in May 1998; this  
25 became Docket No. 6107. Following filing of direct testimony (including my  
26 testimony on the costs of the imprudent lock-in), the parties reached an

1 interim settlement that set temporary rates, pending developments in GMP's  
2 efforts to renegotiate the HQ-VJO contract. The failure of those efforts led  
3 GMP to reopen Docket No. 6107 in September 2000 with the filing of re-  
4 buttal testimony. The Board approved a settlement in that proceeding in  
5 January 2001. The Board found that "a prudent mix of resources could have  
6 been purchased in 1991–1992 that, in aggregate, would have cost GMP  
7 between three and five-and-a-half cents per kWh from 1992 until the mid-  
8 2000s" (Docket No. 6107 Order at 44). The Board found (at 49) that  
9 disallowing all imprudent costs "would clearly put a significant strain upon  
10 GMP's financial viability" and imposed a smaller disallowance to avoid  
11 forcing the utility into bankruptcy.

12 **Q: Is prudence an issue in this case?**

13 A: Whether CVPS was prudent in its decision to lock into the HQ-VJO contract  
14 is not an issue in the current proceedings. The question is what CVPS would  
15 have done if it had acted prudently is very much at issue in this case.  
16 Reconstructing prudent actions requires the identification of the information  
17 that would have been available to a prudent utility, and the types of analyses  
18 that a prudent utility would have performed, both before the premature lock-  
19 in and afterwards.

20 For the most part, I rely on the planning assumptions and methods that  
21 CVPS was using in the early 1990s. Where CVPS's approach was not  
22 representative of a prudent utility, faced with major resource decisions, I  
23 explain why and provide corrections.<sup>3</sup> In all such discussions, my intention is

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<sup>3</sup>Some of Central Vermont's approaches may have been reasonable for a utility that did not perceive that it had any choice regarding its most important resource commitment. Central Vermont may have believed that it was in that situation, with regard to the HQ-VJO contract.

1 to identify replacement resources and estimate damages, not to reopen argu-  
2 ments over the imprudence of the lock-in. Any references to “prudence” in  
3 this testimony relate either to the context (e.g., CVPS’s situation if it had  
4 *prudently* avoided the HQ-VJO lock in) or the *prudent* choice of inputs and  
5 approaches for selecting resources.

6 **C. Summary of Conclusions**

7 **Q: Would a prudent analysis in the fall of 1991 have indicated that the HQ-**  
8 **VJO contract was desirable for Central Vermont’s ratepayers?**

9 A: No. Had Central Vermont avoided the early lock-in and prudently compared  
10 the HQ-VJO contract to the alternatives, it would not have found the  
11 economics of the contract to be improving later in 1991.

12 **Q: Would a prudent utility ever have locked into the HQ-VJO contract**  
13 **after August 28, 1991?**

14 A: No. Had Hydro Québec offered a substantially improved contract, Central  
15 Vermont might have prudently purchased some long-term resources from  
16 Hydro Québec.

17 **Q: What was the Company likely to have done if it had avoided the HQ-**  
18 **VJO lock-in?**

19 A: As the Board found with respect to Green Mountain Power in Docket No.  
20 5983, the Company and the rest of the Vermont Joint Owners would have  
21 canceled the contract sometime in 1992, as the contract’s economics

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The Board and the Supreme Court have now settled the issue of whether the Company had a choice (it did), and it really does not matter whether CVPS’s approach might have been adequate for another utility in another situation.

1 continued to deteriorate (Docket No. 5983, Order at 240). Starting in 1992,  
2 the Company would have been looking for replacement power supplies.

3 Because of the glut of power in the Northeast, the Company would have  
4 faced many options for short- and medium-term power purchases, at costs  
5 lower than those of new resources. As a result, the Company would probably  
6 have replaced the HQ-VJO purchase with a set of contracts covering the  
7 period from late 1995 (when CVPS's major purchases from HQ started) until  
8 sometime after 2000.<sup>4</sup> These contracts would most likely have included  
9 purchases from some combination of NU, UI, NEPCo, and the New York  
10 utilities.<sup>5</sup>

11 It is more difficult to determine when the Company would have signed  
12 those contracts, exactly how they would have been structured, with whom  
13 they would be, and how much they would cost today. By late 1991, CVPS was  
14 not planning to make significant purchases under the HQ-VJO contract until  
15 late 1995, and the full contract level would not be reached until late 1996.  
16 The cancellation of the HQ-VJO contract in late 1991 would not have  
17 required any immediate need for major resources, and Central Vermont  
18 would have had considerable flexibility about the timing of its purchases. As  
19 I discuss below, market prices for multi-year power purchases were falling  
20 dramatically in this time period.

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<sup>4</sup>Central Vermont had originally contracted for significant capacity starting in 1991, with further increases in 1996. By late 1991, CVPS had sold back to HQ nearly all of its purchases for 1992 through late 1995.

<sup>5</sup>The Company would probably also have started planning to participate in a utility-owned or NUG combined-cycle plant (and perhaps a combustion turbine, as well) around 2005, but that plant would never have been built, given the change in industry structure.

1           The Board will never know exactly what contracts the Company could  
2           have negotiated in the 1992–95 period to replace the HQ-VJO contract, since  
3           Central Vermont was not actively negotiating to purchase—and indeed was  
4           attempting to sell—long-term baseload resources at this time. Few New  
5           England utilities were seeking new medium-to-long-term supplies in 1991–  
6           1992, due to the glut of resources that contributed to the poor economics of  
7           the HQ-VJO contract. By 1993, several smaller utilities started lining up new  
8           supplies. In addition, Northeast Utilities offered the Company and other  
9           utilities mid-term power sales in 1991, and two New York utilities (New  
10          York State Electric and Gas and Niagara Mohawk) offered power to Central  
11          Vermont Public Service in 1992.<sup>6</sup>

12           Due to its failure to reconsider and reject the HQ-VJO contract, the  
13          Company never developed a prudent mix of resources in the period from  
14          1992 through the present. Yet it is the excess cost of the HQ-VJO contract in  
15          the rate years (2001–02), above the cost of the prudent portfolio, that  
16          determines the cost of Central Vermont’s imprudence. Hence, the Board must  
17          select a proxy for the mix of resources that CVPS would have developed,  
18          absent imprudence.

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<sup>6</sup>There may have been other offers, but these are the only offers that have been made public. If the HQ-VJO contract had been canceled, HQ would almost certainly have been marketing firm energy to New England, at least enough to use the otherwise idle capacity of the Highgate station.



1     **III. The Prudent Resource Mix Following the Vermont Joint Owners'**  
2     **Refusal to Lock In to the Contract**

3     **Q: What would have happened to the HQ-VJO contract had CVPS and the**  
4     **Joint Owners not agreed to the premature August lock-in?**

5     A: That would depend on what actions CVPS, the Joint Owners, and HQ would  
6     have taken after August 1991. Had Central Vermont acted prudently, it would  
7     not have locked into the HQ-VJO contract by the November 30, 1991  
8     deadline. Either HQ would have granted the Joint Owners an extension of the  
9     lock-in date, as it did for New York (which agreed with HQ on a one-year  
10    extension at the same time CVPS was agreeing to the lock-in), or the Joint  
11    Owners would have canceled the contract prior to November. At that time the  
12    utilities faced

- 13       • continuing decline in loads and fuel prices forecast, and in market  
14       power costs;
- 15       • HQ's deteriorating bargaining power in light of the lack of enthusiasm  
16       on the part of New York for completing its proposed purchase of HQ  
17       power (let alone absorbing any of the VJO sale);
- 18       • likely re-examination of the contract by the Board.

19    These factors would probably have led to either the termination of the HQ-  
20    VJO contract, or to steep reductions in the prices, term, size or restrictions in  
21    the contract.

22       In the event of termination, CVPS might conceivably have opted to  
23    replace the HQ contract with another long-term single-source contract, but  
24    few major long-term power-purchase commitments were made by New  
25    England utilities after the end of 1991. I doubt that CVPS would have been  
26    able to contract for such a purchase and get it approved before falling market

1 prices rendered it uneconomic. The Company would more likely have  
2 purchased power primarily on the short- and medium-term market.

3 Following the cancellation of the HQ-VJO contract, CVPS would have  
4 been in the position of several utilities that were actively seeking power-  
5 supply arrangements in 1992. Had Central Vermont acted prudently at that  
6 time, it would have diversified its supply sources and contract structures, and  
7 contracted for a variety of supplies. It would also have increased its emphasis  
8 on energy conservation.

9 **Q: What modifications in the HQ-VJO contract might have made it more**  
10 **attractive?**

11 A: The utilities might have negotiated some combination of the following:

- 12 • The purchase of smaller amounts of HQ power, perhaps at the level of  
13 Schedule B, to utilize the Highgate interconnection.
- 14 • A shorter contract term, to minimize the uncertainties for both the seller  
15 and the buyers from the long contract.
- 16 • Lower prices, which would have been necessary to bring the costs down  
17 to the level of alternatives, as well as to compensate for any reduction in  
18 the length of the contract.

19 Unless the parties and the Board had acted very quickly, or HQ cut  
20 prices very dramatically, events would have continued to catch up with the  
21 contract. Throughout the early 1990s, fuel prices and fuel-price forecasts  
22 continued to fall, the expected costs of new gas-turbine and combined-cycle  
23 capacity declined, and capacity and energy surpluses continued to grow. A  
24 contract revision that would have looked fine in (for example) October 1991  
25 might well have been unattractive before the Board could complete its  
26 review, sometime in 1992. Hydro Québec did not seem inclined to move

1 quickly on any major price reductions, so it was unlikely to work out a major  
2 long-term sale to Central Vermont that could pass regulatory review. Had  
3 Hydro Québec made major concessions quickly enough, the final contract  
4 might well have been comparable to the prices of the offers and contracts I  
5 discuss below.

6 **A. *The Company's Economic Analyses of Supply Resources in 1991***

7 **Q: Can the Board determine what resource mix CVPS would have selected,**  
8 **had it been acting prudently, from the analyses the Company conducted**  
9 **in 1991?**

10 A: No, for a couple of reasons. First, Central Vermont did not leave clear paper  
11 trail of its long-term supply analyses in this period, especially with regard to  
12 alternatives to the HQ-VJO contract. While CVPS provided some workpapers  
13 in its testimony in Docket No. 5701 and numerous boxes of files in discovery  
14 in Docket No. 6018, the documentation supporting its analyses of the HQ-  
15 VJO contract is incomplete and poorly organized<sup>7</sup>, as the Board found in  
16 Docket No. 5701 at 107–108. Even in 1995, CVPS was not able to produce  
17 much coherent discussion of its 1991 economic analyses of the HQ-VJO  
18 contract, even in the form of the internal memos that would be a necessary  
19 part of any careful review of results by analysts, managers, or the CVPS  
20 Directors.

21 The Company has produced some materials (mostly spreadsheet print-  
22 outs, graphs and handwritten notes) for analyses conducted in February and  
23 April of 1991, and a memo with some documentation of its October 1991

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<sup>7</sup>The Department reviewed every file in every one of more than 50 boxes that CVPS made available for inspection in Docket No. 6018.

1 analysis of potential renegotiation of the HQ-VJO contract.<sup>8</sup> The 1991 IRP,  
2 issued in September 1991, also provides some insight into the input values  
3 that Central Vermont was using at this time.

4 **Q: Please provide a brief description of CVPS's economic analyses of the HQ**  
5 **contract.**

6 A: The Company conducted analyses in February, April, and October 1991, as  
7 summarized in Exhibit DPS-PLC-2.<sup>9</sup> These studies compared the HQ base  
8 case to cases in which the HQ capacity was replaced with various combina-  
9 tions of the following supply options: short-term purchases, long-term  
10 purchases of NU oil-fired capacity, the Sheldon Springs NUG (which was  
11 also called Bonneville), generic gas turbines, and intermediate and baseload  
12 combined-cycle plants.<sup>10</sup>

13 The February 1991 analysis compared the HQ contract to two  
14 alternative portfolios consisting of a mix of generic new units and short-term  
15 purchases, with and without purchases from Sheldon Springs.

16 The April 1991 study examined several alternative supply portfolios.  
17 The lowest-cost expansion plan described in the available documentation  
18 consisted of the "oil block" (a 110 MW purchase from the Middletown-4 and  
19 Montville-6 oil-fired units of Northeast Utilities), Sheldon Springs, and

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<sup>8</sup>Most of these materials were provided in CVPS Exhibit EMA R-1 in Docket No. 5701, which I refer to herein simply as Exhibit EMA R-1. I have not identified any substantially different analyses in the boxes of files provided on discovery in Docket No. 6018.

<sup>9</sup>Exhibit DPS-PLC-2 is based primarily on Exhibit EMA R-1.

<sup>10</sup>The two types of combined-cycle units represented the same technology, and differed principally in fuel supply. Central Vermont modeled the intermediate combined-cycles as burning a mix of oil and interruptible gas, and modeled the baseload combined-cycle plants as burning firm gas (and hence paying fixed pipeline demand charges).

1 generic combined-cycle and combustion-turbine units. The analyses in the  
2 April study reflect the first sellback.

3 The April 1991 analyses indicated that the HQ purchase was less  
4 expensive than the lowest-cost alternatives modeled by as little as \$16  
5 million in present-value terms, and was more expensive than the alternatives  
6 through 2012, three years before the end of the contract.

7 Also in April 1991, CVPS's planning staff met to consider the lock-in.  
8 Company planners apparently believed that these results were overstated, and  
9 that the present-value benefits of the HQ contract were in the range of \$16–  
10 \$35 million (Exhibit DPS-PLC-3). The second sellback, to which CVPS and  
11 HQ had agreed in principle (but had not made final), was expected to reduce  
12 the cost of the purchase by \$19 million, bringing the range of benefits, under  
13 the conditions of the April study, to \$35–\$54 million (Exhibit DPS-PLC-3).  
14 The planners recommended unanimously that the Company not commit to  
15 the contract.

16 The October 1991 analysis was the first Company analysis to use the  
17 lower projection of fuel prices that CVPS had developed in July 1991.<sup>11</sup> Of  
18 the six cases in the October analysis, five assumed the existence of the HQ-  
19 VJO contract, and reflected the benefits of alternative sellback and banking  
20 arrangements. The remaining case (Case 6) assumed the cancellation of the  
21 HQ-VJO contract, and its replacement with NU's Montville and Middletown  
22 units, followed in 1999 by new utility-owned proxy units of unspecified  
23 technology. Central Vermont found Case 6 to be \$90–100 million more

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<sup>11</sup>The analysis is described in a 10/29/91 memo from Amelang, Dodds, and Rochelle to Cater, which is part of Exhibit EMA R-1. It is also contemporaneous with the Company's 1991 IRP, and probably used similar assumptions.

1 expensive in present value than three cases that included the HQ-VJO  
2 contract with the first two sellbacks and various assumptions about banking  
3 and other factors. As I discuss below, the Company did not choose  
4 appropriate replacement resources for Case 6, and made a number of  
5 incorrect assumptions about the cost of new units.

6 **Q: Are the input assumptions in these analyses appropriate for determining**  
7 **the least-cost replacement for the HQ-VJO contract?**

8 A: No, for several reasons. First, Central Vermont does not appear to have  
9 sought out the best purchase options to replace the HQ-VJO purchase.  
10 Second, the replacement portfolios that CVPS selected were not well  
11 calculated to minimize costs. Third, several of the inputs to the analyses were  
12 not appropriate.

13 **Q: Please explain why Central Vermont's analyses do not necessarily reflect**  
14 **the best purchase options available at the time.**

15 A: Central Vermont appears to have artificially limited its alternatives, by asking  
16 suppliers for a very specific product, which would look like the HQ contract  
17 with certain improvements. In a letter of 7/12/91, for example, CVPS asked  
18 Northeast Utilities for a bid to supply power from 1996 to 2010, in varying  
19 amounts, with options for CVPS to elect additional purchases on short notice.  
20 Central Vermont asked that the pricing terms also mirror those in HQ, with  
21 energy escalating with GNP inflation throughout the contract and capacity  
22 escalating at GNP inflation until the start of each increment of capacity.  
23 Central Vermont should have been aware that other utilities in New England  
24 were not anticipating excess supply of low-cost power past about 2005;

1 demanding a purchase of this length, with options, and with the specific HQ  
2 escalation provisions, might well have discouraged potential suppliers.<sup>12</sup>

3 In addition, even though Northeast Utilities had offered to tailor a  
4 contract to meet CVPS's needs, there is no evidence that the Company made  
5 any serious effort to negotiate with NU, other than the inappropriate request  
6 described in the above paragraph.<sup>13</sup>

7 **Q: Please describe the problems with the Company's replacement portfolios.**

8 A: I have identified three such problems.

- 9 • The April 1991 analysis assumed that CVPS would purchase more NU  
10 capacity than it needed 1995–98, which would overstate the benefits of  
11 HQ.
- 12 • In February 1991, NU offered CVPS three purchase options: a mix of  
13 specific nuclear and oil plants, system power, and the oil block. The  
14 available documentation on the nature of the offers is contained in  
15 Exhibit DPS-PLC-4. The system-power offer was by far the lowest-cost  
16 NU offer, as illustrated in Exhibit DPS-PLC-5. Nevertheless, CVPS  
17 decided to exclude this option from its analyses of alternatives to the  
18 HQ-VJO contract:

19 ...CVPS had reservations regarding the basis of the energy rates  
20 contained in [the system power option]. The rates appeared to have  
21 been simply estimated at 2 cents/kWh and escalated at oil price  
22 escalation rates. (EMA Direct in Docket No. 5701 at 70)

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<sup>12</sup>The notes of the 4/17/91 planners meeting similarly indicate a concern that “no other alternatives [are available] to 2015.” Clearly, Central Vermont had plenty of time to develop alternatives beyond 2000; the absence of any other proposal for 25 years of sales should not have reduced CVPS's interest in reducing costs in the first decade of the HQ contract.

<sup>13</sup>See the letter from NU to the Department in Exhibit DPS-PLC-4.

1           Rather than developing greater confidence in the pricing of the NU  
2           system power option, CVPS merely assumed for the purposes of the  
3           October analysis that the best it could do was the higher-cost 110-MW  
4           oil block.

- 5           • The October analysis included an NU purchase as a replacement for HQ  
6           only until 1999; after that, the analysis constrained the NU purchase to  
7           21 MW, and all additional deficiencies were met with higher-cost new  
8           units.
- 9           • In the October analysis, CVPS assumed that Sheldon Springs was  
10          canceled and no NUG power would be available in either the short or  
11          long term. As a result, CVPS assumed that the new units replacing the  
12          HQ-VJO contract after 1999 would be generic utility-owned combined-  
13          cycle units, which CVPS expected to be significantly more expensive  
14          than Sheldon Springs.<sup>14</sup>

15   **Q: Had CVPS been considering major long-term purchases in late 1991 or**  
16   **1992, what portfolio should CVPS have compared to the HQ-VJO con-**  
17   **tract, or whatever alternative Hydro Québec would have been offering**  
18   **at that time?**

19   A: Central Vermont should have assembled an efficient low-cost portfolio to use  
20   as a benchmark for comparison with the HQ purchase and other planning  
21   purposes . That portfolio would comprised the following:

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<sup>14</sup>Since Central Vermont acknowledged on discovery (IR 5-42) that other NUGs were offering prices similar to those of Sheldon Springs, that plant's cost could have been used as a proxy for the cost of new NUGs, without requiring any judgement regarding the continued availability of that specific site for development.



- 1       • Through about 2005, one or more of the best purchase deals available  
2       from the owners of existing capacity. This may have included purchases  
3       from NU, UI, NEPCo, NYSEG and/or NiMo. A few other utilities and  
4       NUGs with uncommitted capacity might also have been potential  
5       suppliers.
- 6       • Following the end of the period in which purchases from excess  
7       capacity were available, new combined-cycle capacity. With CVPS's cost  
8       assumptions, the least-cost option would have been a NUG purchase, at  
9       the cost of Sheldon Springs, which CVPS has described as being typical  
10      of other options available in the market. Cost inputs more realistic than  
11      those used by CVPS would result in similar costs for utility-owned and  
12      NUG units.

13   **Q: Can the Board rely on CVPS's 1991 analyses to determine the com-**  
14   **position and cost of the least-cost portfolio from a late-1991 or 1992**  
15   **perspective?**

16   A: Not entirely. Each of CVPS's analyses in 1991 used inputs or selected  
17   resources that would have been inappropriate in assembling and evaluating  
18   benchmark portfolios in late 1991 and 1992.<sup>15</sup>

19   **Q: Please describe the problems with the inputs to Central Vermont's**  
20   **analyses.**

21   A: I have identified two such problems.

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<sup>15</sup>Whether these inputs and assumptions were reasonable at the time they were used is not necessarily relevant to the issues in this case. My interest here is solely in identifying the nature and costs of the resources CVPS should have been considering in deciding how to replace the cancelled HQ-VJO contract.

- 1       • The February and April analyses used high fossil fuel prices from  
2       WEFA's February 1990 fuel-price forecast. CVPS produced a drama-  
3       tically lower fuel-price forecast in 7/10/91.<sup>16</sup> The two fuel-price fore-  
4       casts are summarized in Exhibit DPS-PLC-6. CVPS's 7/91 oil-price fore-  
5       cast for 2005 was almost 30% below the WEFA 2/90 forecast. The  
6       Company's 7/91 forecast was much more in line with the assumptions  
7       of other utilities in the region.
- 8       • Overstating the cost of power from intermediate and baseload  
9       combined-cycle units.<sup>17</sup> The avoided-cost inputs specified in the  
10      Company's 1991 IRP indicate that CVPS overstated the heat rates,  
11      construction costs and pipeline costs for the combined-cycle units and  
12      incorrectly modeled the dual-fuel operation of the intermediate  
13      combined-cycle units.

14   **Q: Why do you say that CVPS used pipeline costs that were too great?**

15   A: The Company assumed pipeline demand costs of \$1.33/MMBtu, or  
16      \$485/MMBtu-day of pipeline capacity, in 1990 dollars.<sup>18</sup> CVPS assumed that

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<sup>16</sup>Company witnesses in Docket 5701 did not reveal the existence of the 7/91 fuel-price forecast in their testimony discussing the costs of alternatives.

<sup>17</sup>The distinction between intermediate combined-cycle and baseload combined-cycle plants, which was often made in New England analyses in the early 1990s, is one of fuel supply. The fixed cost of a baseload combined-cycle includes a pipeline charge, which gives it access to relatively low-cost gas throughout the year. The intermediate combined-cycle fixed costs do not include pipeline charges; without firm pipeline capacity, the plant would burn interruptible gas when regional gas demand is low (i.e., when weather is warm), and much more expensive #2 oil (essentially the same as home heating oil) the rest of the year.

<sup>18</sup>This is \$1.33/MMBtu of peak use. At a 75% capacity factor, that would be more like \$1.77/MMBtu actually used.

1 the pipeline costs would escalate at 1% above the general inflation rate to and  
2 beyond the in-service date of each combined-cycle unit. This pipeline cost  
3 was about half of CVPS's estimate of the total annual fixed costs of a baseload  
4 combined-cycle unit. This value was much too high.

5 The NEPOOL Generation Task Force (GTF), in its "Long-Range  
6 Planning Study Assumptions" (April 1991) estimated pipeline fixed charges  
7 of \$0.65/MMBtu in 1990 dollars, inflated to the in-service date and held  
8 constant thereafter. The starting price was half what Central Vermont  
9 assumed. In addition, holding pipeline charges constant after the start of  
10 deliveries—which would be consistent with common contract and tariff  
11 provisions—would significantly reduce the life-cycle costs of a baseload  
12 combined-cycle plant.

13 **Q: Were the GTF's 1991 estimates of pipeline costs dramatically different**  
14 **from earlier estimates?**

15 A: No. The GTF in 1989 had projected a pipeline fixed charge of \$1/MMBtu,  
16 but assumed no escalation, either to the power plant's installation date or  
17 afterward.<sup>19</sup> Thus, the 1989 GTF assumptions implied a pipeline charge of  
18 \$1/MMBtu for a plant entering service in 2006, compared to \$1.22/MMBtu  
19 for the 1991 GTF assumptions. These are quite similar, compared to CVPS's  
20 extraordinary assumption of \$2.49/MMBtu in the first year and  
21 \$3.41/MMBtu by 2014.<sup>20</sup>

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<sup>19</sup>The GTF did not produce an assumption report in 1990.

<sup>20</sup>I used a 4% inflation rate, which was the long-term inflation estimate Central Vermont used in its 1991 IRP.

1 For comparison, Central Vermont's projection of short-term market  
2 prices in this proceeding assumes a charge of \$0.64/MMBtu or  
3 \$232/MMBtu-day.

4 **Q: What is your basis for saying that CVPS overstated the capital costs of**  
5 **the combined-cycle units?**

6 A: Central Vermont used an overnight construction cost of \$760/kW (1989\$),  
7 which with inflation and AFUDC was equivalent to a gross installed cost of  
8 \$802/kW in 1990 and \$1,081/kW in 1996.<sup>21</sup> These estimates were based, at  
9 least roughly, on the cost estimate for a 100-MW "conventional" combined-  
10 cycle unit from the 1989 GTF report.<sup>22</sup> The GTF reported prices about 10%  
11 lower for a 200-MW combined-cycle, and another 10% lower for a 400-MW  
12 combined-cycle plant.

13 Since Central Vermont would need 142 MW to replace the HQ-VJO  
14 contract, and could share ownership with other utilities (in Vermont and  
15 elsewhere), the choice of a 100-MW unit seems unnecessarily small.<sup>23</sup> Other  
16 New England utilities were proposing, with more or less specificity, new  
17 combined-cycle units ranging from 100 MW to 300 MW.

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<sup>21</sup>From the 1991 IRP (at Table III.E-3), it appears that CVPS computed plant costs based on winter ratings, and increased the capital cost slightly to reflect the summer derating of the plant.

<sup>22</sup>The base plant cost that CVPS used (in 1989 dollars) is a few percent *greater* than the GTF's estimate (in 1990 dollars), suggesting that CVPS added a year's inflation, rather than subtracting it.

<sup>23</sup>As late as October 1991, Central Vermont anticipated the need for an additional 230 MW of new resources by 2006, even with the HQ-VJO purchase. (at Exhibit 2 of the 10/91 analysis in Exhibit EMA-R1)

1           The GTF's capital costs were in turn based on a 1987 report from Burns  
2           and Roe, and also anticipated much lower costs for advanced combined-cycle  
3           designs. Central Vermont should have checked these estimates. As of the  
4           early 1990s, there was little recent public information on the costs of  
5           building combined-cycle plants. The relatively few existing utility combined-  
6           cycle plants were of 1970s vintage, and the combined-cycle plants under  
7           construction in the early 1990s were mostly NUGs, which need not publicly  
8           report their costs.<sup>24</sup>

9           There was one readily available data point. In 1990, Virginia Power  
10          added the Chesterfield-7 gas combined-cycle unit at a price of \$490/kW.<sup>25</sup>  
11          That unit had some advantages: it was built at an existing site, and in a less-  
12          expensive part of the country (and its reported cost probably did not include  
13          its transmission interconnection). A new unit in New England in 1990 would  
14          be expected to be somewhat more expensive, but probably not by the 60%  
15          difference between CVPS's estimate and the actual cost of Chesterfield 7.

16          Had CVPS contacted other utilities' planning and construction staffs, it  
17          might have also obtained data on the projected costs of plants under or near  
18          construction, including the following (all costs are in nominal dollars, winter  
19          capacity):

- 20          •     Chesterfield 8 was completed in 1993 for \$546/kW

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<sup>24</sup>It is not clear that NUG cost data from the late 1980s and early 1990s would be applicable to utility-owned plants. For many NUG units, prior to the adoption of competitive bidding, completion of the unit in time to meet contract requirements for a lucrative purchased-power agreement may have been more important than controlling costs.

<sup>25</sup>Chesterfield cost should have been filed in the Virginia Power FERC Form 1 in April 1991. I do not have that document, but Chesterfield's 1990 capital cost is included in the Utility Data Institute database, which is taken primarily from the FERC Form 1.

- 1       • Martin 3&4 (Florida P&L), which were completed in 1993 and 1994 for  
2       an average cost of \$513/kW.
- 3       • RM Flynn (a New York Power Authority greenfield plant on Long  
4       Island), which was completed in 1994 for \$723/kW.
- 5       • Hay Road (Delmarva P&L), where the turbines were installed in 1990-  
6       91 at less than \$300/kW and the combined-cycle was completed in 1993  
7       for an average cost of \$469/kW.
- 8       More details on these plants are provided in Exhibit DPS-PLC-7.

9       **Q: How did CVPS overstate the heat rates of the combined-cycle units?**

10      A: The Company assumed a full-load heat rate of 8,900 btu/kWh for baseload  
11      combined-cycle plants and 9,300 for intermediate combined-cycle units.  
12      Since these plants are otherwise treated as being identical (other than their  
13      fuel supply), the higher heat rate for the intermediate units would be hard to  
14      explain. In fact, combined-cycle units have lower heat rates on oil, and the  
15      intermediate units were assumed to burn oil for a large part of the year, so  
16      they should have had lower full-load heat rates.<sup>26</sup>

17              Other sources of heat-rate information at the same time indicated much  
18      higher efficiencies:

- 19      • Chesterfield's 1990 heat rate was 8,149 BTU/kWh, operating at a 30%  
20      capacity factor. Baseload operation should produce a lower heat rate.

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<sup>26</sup>Most thermal plants, and especially gas-turbine and combined-cycle units, operate at higher heat rates at part load. The annual heat rates of intermediate units, which spend more of their time at a partial load, would therefore typically be higher than those of baseload units of the same design. The difference is modeled directly in UPLAN, which uses different heat rates for different load levels, for the new combined-cycles and for most other thermal plants. The difference in full-load heat rate is in addition to the effects of partial loading.

- 1       • The 1989 GTF report listed full-load heat rates for conventional  
2       combined-cycles of 200–400 MW as 8,214 Btu/kWh.<sup>27</sup> The IRP  
3       indicates that “The Company increased the GTF Assumptions heat rates  
4       to allow for slightly lower efficiency” (at III.E-4), but does not explain  
5       why CVPS believed that future combined-cycle units would be less  
6       efficient than the GTF expected for conventional designs. In any case, a  
7       13% increase in heat rate hardly qualifies as “slight.”
- 8       • The 1991 GTF slightly increased the estimate of full-load heat rate for  
9       conventional combined-cycles, to 8,385 Btu/kWh, still less than CVPS’s  
10      estimates of 8,900–9,300.

11   **Q: How did CVPS incorrectly model the dual-fuel operation of the inter-**  
12   **mediate combined-cycle units?**

13   A: In its 1991 IRP, Central Vermont modeled the dual-fueled intermediate  
14   combined-cycle plant as operating year-round on a single fuel, which appears  
15   to be priced at the average of the prices of #2 oil and interruptible gas.  
16   Normal UPLAN modeling would have treated the intermediate combined-  
17   cycle as two units: a gas-fired unit with a lower fuel cost that is available  
18   only in the summer and an oil-fired unit with a higher fuel cost that is  
19   available only in the winter. Had CVPS used this approach, UPLAN would  
20   have modeled the unit’s dispatch as more frequent in the summer and less

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<sup>27</sup>Advanced combined-cycle units were listed as having heat rates around 7,400 Btu/kWh. These might reasonably be thought of as speculative in 1991, although Martin County reported a heat rate under 7,300 for 1994.

1 frequent in the winter, resulting in a lower-cost fuel mix and a reduction in  
2 total energy cost.<sup>28</sup>

3 The assumption that the intermediate combined-cycle would be burning  
4 gas half the year was also very conservative. In 1991, gas was available  
5 virtually all year: several New England power plants were burning  
6 interruptible gas in January. While supplies might be more limited in some  
7 years, the average amount of time that interruptible gas would be available  
8 would almost certainly be more than one half.

9 Had CVPS included an intermediate combined-cycle plant in a resource  
10 portfolio, it should have modeled the dual fuel use more realistically than it  
11 did in 1991. I avoid this complication by using a baseload combined-cycle  
12 (either utility-owned or combined-cycle) rather than an intermediate unit.

### 13 ***B. Available Resources and Other Indicators of Market Prices***

#### 14 ***1. Excess Capacity in New England***

15 **Q: How had the availability of capacity and energy from New England**  
16 **utilities changed between the approval of the HQ-VJO contract in**  
17 **Docket No. 5330 and the post-lock-in period in which CVPS should have**  
18 **been seeking replacement of the HQ-VJO contract?**

19 **A:** The following factors had changed:

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<sup>28</sup>In a smaller error, CVPS escalated the cost of gas for the baseload combined-cycle, not at the rates assumed for gas in CVPS's fuel forecast, but at the slightly higher escalation rates assumed for #2 oil.



- 1       • The economy of Vermont and the region was deteriorating (Docket  
2       5701, Order at 107 and 109).
- 3       • The NEPOOL CELT report released on April 1, 1991, dramatically  
4       reduced projected load growth in NEPOOL. Combined with the operation  
5       of new supply resources, such as Seabrook, the HQ Phase II line, and  
6       NUGs, the load reduction moved back the need date for new capacity  
7       from 1995 to 2000. (Docket 5701, Order at 108-109)
- 8       • NU, the utility generally perceived to have the most excess capacity,  
9       was offering power through 2005 or 2006, and its March 1991 System  
10      Forecast of Loads and Resources showed adequate reserves through  
11      about 2004.
- 12      • As the CVPS planners noted at their 4/17/91 meeting, it was a “buyer’s  
13      market—we are a buyer” (notes reproduced at Exhibit DPS-PLC-3).
- 14      • Regional market power prices for the short and medium terms were  
15      falling (Docket 5701, Order at 114).

16   **Q: What additional medium or long-run purchase contracts were signed by**  
17   **New England utilities in the early- to mid-1990s?**

18   A: Most New England utilities were not in the market for additional medium or  
19   long-run purchases in this period. Most of the larger utilities were selling  
20   power, rather than buying. However, some of the smaller utilities obtained  
21   power supplies in this period, primarily to replace cancelled supplies. I have  
22   identified three cohorts of contracts signed by New England utilities in the  
23   early-to-mid 1990s:

- 24      • Until’s acquisitions from its 1991 Request for Proposals.
- 25      • A number of purchases by municipal utilities negotiated in 1992 and  
26      signed in 1993.

- 1       • Purchases negotiated by Burlington Electric Department and New  
2       Hampshire Electric Cooperative in 1995.

3   **Q: Please describe the Unitil acquisitions.**

4   A: In late 1991, Unitil selected the winners in its April 1991 RFP. Unitil rejected  
5       CVPS's offers of Schedule B at cost through 2015, in favor of purchases from  
6       NU, UI, NEES, and MMWEC.<sup>29</sup>

7       Unitil selected a mix of oil, gas (steam and combined-cycle), coal, and  
8       nuclear. This power would come from six utilities, nine plants, and eleven  
9       units; and with expiration dates ranging from April 2001 to April 2013. Over  
10      half the capacity was in contracts that would expire in 2005–2006. This is a  
11      reasonable model for prudent behavior by CVPS a year or so later. Exhibit  
12      DPS-PLC-8 shows the 1999 costs of each of Unitil's commitments made in  
13      this period, at their actual capacity factors and adjusted to 75% capacity fac-  
14      tors, assuming that additional energy would purchased or sold at \$25/MWh.<sup>30</sup>  
15      Other than the Seabrook contract (which was comparable in price to the HQ-  
16      VJO sale), each of the Unitil purchases was less expensive than the HQ-VJO  
17      contract, some by a wide margin.

18   **Q: Please describe the municipal power purchases.**

19   A: Exhibit DPS-PLC-9 summarizes the provisions of ten contracts signed by  
20       eight New England municipal utilities in 1993 to purchase power over  
21       periods of 5–12 years from Boston Edison, NEPCo, or NU.

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<sup>29</sup>The winners were not known in time for the 11/91 issue of *Robertson's Current Competition*, but were listed in the 2/92 issue. At some point, Unitil added a purchase from Great Bay Power, as well.

<sup>30</sup>Unitil's purchase from NEPCo was partially transferred to USGEN when it purchased NEPCo's plants, and some of the component purchases may have been terminated.

1 I have not included unit power purchases priced at cost-of-service, or  
2 contracts that appear to have been continuations of older contracts or  
3 resolutions of disputes. The cost projections do not include contracts that are  
4 difficult to price or evaluate, such as those based on cost of service. The costs  
5 of the NEPCo-Littleton and NEPCo-Braintree contracts include compensa-  
6 tion for NEPCo's payment to buy out the Newbay NUG contract; I have  
7 reduced the projected capacity cost to reflect pricing without the Newbay  
8 payment (about \$60/kW-yr, or 1¢/kWh).

9 The contracts are generally structured as system power purchases,  
10 although the prices are sometimes tied to fuel prices at a particular plant and  
11 availability of energy is sometimes conditioned on the availability of at least  
12 one or two of a group of plants. The inter-utility contracts also generally have  
13 greater flexibility in energy take and capacity adjustment than the HQ  
14 contract, and have shorter terms as well. If they turn out to be somewhat  
15 above market prices, they will not last as long as the HQ contract and will  
16 therefore produce much lower damages.

17 The actual costs (as the resources were dispatched by NEPOOL)  
18 generally fell in the range of 3.9–4.5¢/kWh in 1999, for the power-purchase  
19 contracts whose prices I have been able to find for that year, compared to  
20 5.8¢/kWh for the HQ purchase.<sup>31</sup> The requirements sale by NU to Madison,  
21 Maine cost 4.9¢/kWh, but included reserves, charged the purchaser only for

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<sup>31</sup>The average cost reported for the NEPCo-Reading sale, which ended 10/31/99, was 8.6¢/kWh. This contract provided very little energy in 1999 and appears to have operated more like a peaker than a baseload resource. Had the NEPCo-Reading sale operated at a 75% capacity factor, rather than its actual 35% capacity factor, with the same energy charge and the same total demand bill, the price would have been 5.4¢/kWh.

1 actual load, and allowed the purchaser to change loads as required.  
2 Requirements contracts are more valuable, and should generally be priced  
3 higher, than firm power sales. The NEPCo-Littleton sale cost 5.6¢/kWh, but I  
4 cannot determine how much of that year's price was actually compensation  
5 to NEPCo for paying Littleton's cost for buying out the Newbay NUG  
6 contract.

7 Of the seven contracts for which I have been able to project prices for  
8 2001/02, the prices for six of them range from 4.2¢/kWh to 5.7¢/kWh with  
9 EVA's current fuel-price forecast.<sup>32</sup> The requirements sale by NU to  
10 Madison, Maine would cost 6.7¢/kWh.

11 **Q: Please describe the contract between Northeast Utilities and the**  
12 **Burlington Electric Department.**

13 A: In 1995, the Burlington Electric Department negotiated a contract with NU  
14 for purchases from May 1998 through 2009. The contract, signed in March  
15 1996, is described in Exhibit DPS-PLC-10. Burlington would have paid NU  
16 \$33/MWh in 1999 and \$39/MWh during 2001/02, at the 75% capacity factor  
17 of the HQ-VJO contract.

18 This contract provides very flexible power supply. There is no mini-  
19 mum energy take, energy is a majority of the purchase price, and energy  
20 prices vary between peak and off-peak. Burlington has the option of  
21 changing the capacity of the purchases over a wide range—from 2.5 MW to  
22 7.5 MW—on two months notice. Under these circumstances, the seller  
23 cannot count on above-market (or above-cost) prices in one year balancing

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<sup>32</sup>The EVA forecast was prepared for the Department. Central Vermont relies on the EVA forecast in its projection of short-term market prices.

1 below-market prices in another year; the annual prices in the contract must  
2 represent a reasonable approximation of the price at which the seller would  
3 have been willing to sell in that year, for any length contract.

4 **Q: Please describe the contract between the Company and the New**  
5 **Hampshire Electric Cooperative.**

6 A: On 12/29/94, NHEC issued an RFP to replace its existing contract with CVPS.  
7 Central Vermont responded to the request in January 1995, and the contract  
8 was made final by April 1995. The contract provides for delivery of 2.75  
9 MW at an annual 54% capacity factor, with specific monthly kW and kWh  
10 deliveries, for May 1, 1995 through October 1, 2006. The price for this  
11 power is set at \$32.40/kW-yr and \$14/MWh in 1995, for an all-in price of  
12 \$23.6/MWh, rising at the general inflation rate.<sup>33</sup> Exhibit DPS-PLC-11  
13 compares the contract price, actual prices through 2000, and CVPS's  
14 projection of prices for the rest of the contract term. These prices are less  
15 than half the prices of the HQ-VJO contract.

16 If Central Vermont negotiated the contract with NHEC prudently, these  
17 prices should represent the market in 1995. If Central Vermont had not  
18 locked into the HQ-VJO contract, it might have been a buyer, rather than a  
19 seller, in the 1995 market for medium-term power purchases, and might have  
20 wound up paying prices comparable to those in the NHEC contract.

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<sup>33</sup>Any additional power would be priced at 10% more than CVPS's short-term marginal costs, with a floor capacity price of \$18/kW-yr.

1    2.    *Excess Capacity in New York*

2    **Q: Why is excess capacity in New York relevant to Central Vermont's**  
3    **power-supply planning in the early 1990s?**

4    A: As CVPS's 1991 IRP acknowledges, New York utilities had been, and were  
5    expected to remain, significant power suppliers to New England.

6            This was particularly true in the early 1990s, as New York utilities were  
7    projecting large capacity surpluses, no need for capacity until well after  
8    2000, and sharply lower avoided costs. On August 30, 1991, two days after  
9    the Vermont Joint owners' early lock-in decision, the New York Power Pool  
10   released estimates of long-run avoided costs that were less than those of the  
11   HQ contract and other resources CVPS had been considering, through at least  
12   2004,. See Exhibit DPS-PLC-12.<sup>34</sup>

13   **Q: At what prices were New York utilities offering power in the early**  
14   **1990s?**

15   A: In early 1992, New York State Electric and Gas (NYSEG) and Niagara  
16   Mohawk (NiMo) provided CVPS with power offers. These offers are attached  
17   as Exhibit DPS-PLC-13 and Exhibit DPS-PLC-14. Each utility made two  
18   offers; one of the NYSEG offers is based on a complex definition of marginal  
19   energy costs and is difficult to evaluate. The other three offers are priced out  
20   in Exhibit DPS-PLC-15.<sup>35</sup> I included transmission charges of \$24/kW-yr,

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<sup>34</sup>Due to these conditions, coupled with success of DSM programs, low fuel costs, and the poor economics of the HQ purchase, New York's interest in the HQ purchase was flagging. Agreement on delaying the New York decision from December 1991 to November 1992 was announced in August 1991, the same day as the VJO lock-in decision.

<sup>35</sup>I used NiMo's estimate of its marginal energy costs in evaluating NiMo A.

1 based on the charges in NYSEG's offer. The costs of these offers were  
2 considerably below the costs of the HQ-VJO contract.

3 In 1995, the Burlington Electric Department negotiated a contract with  
4 New York State Electric and Gas for purchases from May 1998 through  
5 2009, respectively. The contract, signed in March 1996, is described in  
6 Exhibit DPS-PLC-16. The prices for 1999 and 2001/02 are equivalent to  
7 \$37/MWh and \$41/MWh at the 75% capacity factor of the HQ-VJO contract.  
8 As with the NU-Burlington contract, this purchase is very flexible.  
9 Burlington has the option of changing the purchase from 2.5 MW to 7.5 MW,  
10 on two months notice.

11 3. *Availability of Transmission from New York*

12 **Q: Was transmission from New York available to CVPS in 1991 and 1992?**

13 A: Yes. The transfer capability across the interface was allocated by agreement  
14 between the three NEPOOL participants that owned lines connecting to New  
15 York: VELCo, NU, and NEPCo. Vermont had access to 14% of the transfer  
16 capability, which was usually approximately 220 MW, but could fall to 170  
17 MW when critical transmission elements were unavailable (IR DPS 5-30 at  
18 1-2).

19 In addition, capacity on the interface could be purchased from the other  
20 two owners. The NY-NEPOOL tie was used largely for economy purchases,  
21 over which a firm purchase would take priority.

22 Capacity on the interface was not heavily used. In April 1991, R. M.  
23 Mallory of VELCo wrote to Central Vermont's R. deR. Stein and others:  
24 "With the recent decrease in power demand, the commissioning of Seabrook,

1 the construction of Phase II and the acceleration of DSM efforts, the demand  
2 for transmission from New York has largely evaporated.”<sup>36</sup> D. James,  
3 NEPOOL’s Manager of Transmission Planning, wrote that during 1992–93,  
4 “New York to NE transfers greater than 1,000 MW have rarely occurred in  
5 recent years (e.g., 8 hours in the past two years).”<sup>37</sup>

6 While New York and NEPOOL transmission planners in this period  
7 prudently attempted to foresee and avoid inter-regional transmission  
8 constraints due to the construction of new plants, the concerns they identified  
9 were generally limited by such qualifiers as “improbable risks,” “rare  
10 circumstances,” and “certain severe and improbable conditions.”  
11 Transmission constraints arose periodically on the NEPOOL side of the  
12 interface; these were mitigated in the short term by the control of generation  
13 dispatch, and were relieved within a year or two by reinforcement of the  
14 transmission system.

15 **Q: Was NYPP-NEPOOL transmission capacity expensive in the early 1990s?**

16 A: No. NYSEG estimated a cost of \$24/kW-yr in 1992 (Exhibit DPS-PLC-13),  
17 which would be about \$4/MWh. Green Mountain Power paid about \$3/MWh  
18 for NYPA to wheel power from Ontario Hydro in 1990 through 1993, and also  
19 reserved 50 MW of NU’s transfer capability for its purchase from RG&E,  
20 through 1997 (although the contract was cancelled earlier). Green Mountain

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<sup>36</sup>“VELCo’s Study of the New York to Vermont Interface,” April 12, 1991, at 2, ¶2. Exhibit GMP-RJB-2 of the testimony of Richard Bolbrock, Docket 5983, 1/9/98.

<sup>37</sup>Letter to M. DeLaura, Chairman, Task Force on System Studies, New York Power Authority, “Re: TFSS Review of the Potential InterArea Effects of the Saranac Energy NUG,” September 1, 1993, at 1, ¶4. Exhibit GMP-RJB-1 of the testimony of Richard Bolbrock, Docket 5983, 1/9/98.



1 Power paid about \$16/kW-yr for NU transmission capacity in 1990, and  
2 much less (under \$1.5/kW-yr) in 1991 and 1992 (GMP's FERC Forms 1 for  
3 various years at 332).

4 **Q: Were the New York utilities concerned that NUG construction might**  
5 **restrict their ability to sell their excess capacity into NEPOOL?**

6 A: No. Niagara Mohawk, which was a major seller of power to New England  
7 with every reason to keep transmission capacity open, reported in its Septem-  
8 ber 1991 IRP (at 6-15) that the NYPP-NEPOOL Interface "is currently limited  
9 by lines in New England which may be upgraded in the future.... Subject to  
10 specific study, new [NUG] resources in Eastern NY are not anticipated to be  
11 detrimental to the NYPP-NEPOOL Interface and, unless shown to be  
12 detrimental to Central-East requirements, should not be discouraged."

13 **Q: Were imports from New York generally assumed to be available to New**  
14 **England utilities in the early 1990s?**

15 A: Yes. For example, in 1994, Boston Edison filed testimony purporting to  
16 demonstrate that it could count on as much as 750 MW of capacity from  
17 New York, even if it did not reserve capacity or transmission in advance. An  
18 excerpt of that testimony is attached as Exhibit DPS-PLC-17.

19 4. *New Plants*

20 **Q: What types of new plants would have been considered as replacements**  
21 **for the HQ-VJO contracts?**

1 A: During the period of excess capacity in New England and New York, no new  
2 plant could compete with the cost of existing plants.<sup>38</sup> Once demand and  
3 supply converged, sometime after 2000, CVPS would have two basic choices:  
4 a purchase from a NUG, or participation (as owner, co-owner, or purchaser)  
5 in a utility-owned plant. As a replacement for the baseload HQ-VJO  
6 purchase, both the NUG and the utility plant would be expected to be gas-  
7 fired combined-cycle units.

8 **Q: Would CVPS have needed to commit itself to a specific new unit in the**  
9 **early 1990s?**

10 A: No. The Company would have used a proxy unit in its economic analyses.  
11 Since that unit would not be needed until 2005 or beyond, CVPS would not  
12 have expected to need to make any specific commitments until about 2000.

13 **Q: What would be an appropriate proxy for a NUG purchase?**

14 A: Based on the documentation CVPS provided in previous dockets, the NUG  
15 with which it was most familiar was Sheldon Springs. The Company  
16 describes Sheldon Springs as typical of IPP's proposed in the early 1990s (IR  
17 DPS 5-42).

18 **Q: What cost assumptions would have been appropriate for a utility-owned**  
19 **combined-cycle plant?**

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<sup>38</sup>In the 1991 IRP, CVPS indicated that the Sheldon Springs project was unlikely to be completed, because "of the declining need for power in Vermont and the Northeast due to the economic downturn" and because "a preliminary Department of Public Service analysis indicates that the need for power has declined" (1991 IRP at VI-5). In other words, given the low cost of oil and the plentiful power supply, Sheldon Springs (and most other NUGs) were not least-cost options in the near term.

1 A: The Company's 1991 IRP provides most of the input data required for the  
2 combined-cycle unit. As described above, the estimates CVPS used for capital  
3 cost should have been reduced somewhat, to reflect the costs of plants  
4 actually constructed in that period. For both heat rate and the cost of gas  
5 transportation from the Gulf, CVPS should have used values similar to those  
6 of the NEPOOL GTF, rather than its own higher values (for which it has not  
7 been able to produce any documentation).

8 **C. *Comparison of the HQ-VJO Contract to Other Alternatives***

9 **Q: How would Central Vermont have compared resource alternatives in the**  
10 **early 1990s, had it been prudently seeking resources to replace the**  
11 **canceled HQ-VJO contract?**

12 A: I assume that CVPS would have taken the basic approach it used in its 1991  
13 IRP. As I describe above, certain of CVPS's input assumptions would need to  
14 be revised.

15 **Q: Have you performed such a comparison?**

16 A: Yes. Exhibit DPS-PLC-18 shows my comparison of the HQ-VJO contract to  
17 the NU system proposal through 2006, followed by a NUG purchase  
18 modeled on Sheldon Springs. I use the input assumptions of the 1991 IRP  
19 and CVPS's October 1991 HQ analyses, except for

- 20 • recognizing the first and second sellbacks, by deleting all HQ costs and  
21 benefits through 1994
- 22 • using the NU system purchase through 2006, with the energy price  
23 CVPS assumed in its analyses (\$22.7/MWh in 1990, escalating with #6  
24 oil price).

1       •     using Sheldon Springs, instead of an over-priced generic combined-  
2             cycle, as the post-2006 replacement. I escalated the Sheldon Springs  
3             variable costs at CVPS's projected escalation in gas prices, and the fixed  
4             charges at CVPS's projected construction inflation to the contract start  
5             date. After the plant's start-up, I follow EMA's assumption that the fixed  
6             costs will increase at 1.1% annually.

7     **Q: What is the result of this analysis?**

8     A: The replacement resources have a lifetime present value that is \$78 million  
9       (or 17%) less expensive than the HQ-VJO contract.

10   **Q: Does this result depend on the use of Sheldon Springs as a proxy for the**  
11       **long-run replacement?**

12   A: No. If CVPS believed that utility-owned plants were inherently more  
13       expensive than NUGs, it should have used a NUG proxy for the later years in  
14       its resource portfolio. A utility combined-cycle unit with more-realistic, but  
15       not aggressive, projections of capital cost, heat rate, and pipeline charges  
16       would have costs comparable to the NUG proxy; see Exhibit DPS-PLC-18.

17   **Q: Is your conclusion that the HQ-VJO contract was more expensive than**  
18       **alternatives dependent on the pricing of the NU system purchase?**

19   A: No. The HQ-VJO contract would also have been predicted in 1991 to be  
20       more expensive than a portfolio including the NU Oil Block; see Exhibit  
21       DPS-PLC-18.

22   **Q: Had CVPS considered the environmental costs and benefits of purchases**  
23       **from HQ contract in comparing resource alternatives, how might that**  
24       **have affected its analyses?**

1 A: For its own planning purposes, in the 1991 IRP and for several years there-  
2 after, CVPS quantified environmental costs only in the calculation of avoided  
3 costs for DSM, as required by Docket No. 5270. The Company sometimes  
4 displayed tradeoffs between costs and environmental effects, but I have not  
5 been able to identify any situations in which CVPS selected resources with  
6 higher costs, to reduce environmental externalities.

7 For example, with respect to supply resources, the 1991 IRP highlights  
8 environmental issues only in terms of the risks related to future  
9 environmental compliance costs, and then only in the last point in twelve-  
10 bullet list (at III.C-9). Similarly, in the 1994 CVEC LCIP, Central Vermont  
11 found that adding new clean generation ahead of need would reduce air  
12 emissions, but took no action toward achieving such additions.

13 **Q: Let us suppose that CVPS had decided to include some consideration of**  
14 **environmental externalities in deciding whether to sign a new contract**  
15 **with HQ, similar to the HQ-VJO contract, or purchase surplus power in**  
16 **New England or New York. How might a prudent Vermont utility have**  
17 **proceeded, given the Board precedent?**

18 A: In considering the environmental effects of the HQ purchase, Central  
19 Vermont might have started with the Board's review of those effects in  
20 Docket No. 5330. In the order of October 12, 1990, the Board stated:

- 21 • "[T]his contract is, compared to other available choices, an  
22 environmentally attractive supply source for Vermont" (Order at 29).  
23 This statement appears to be based on the conclusion that "large-scale  
24 hydroelectric facilities can have significant, negative environmental  
25 effects, but we believe that these effects, properly controlled and  
26 mitigated, are *less* damaging than the alternative supply sources" (Ibid.).

- 1       • “[W]e do not accept the argument that approval of this contract should  
2       ‘cause’ the construction of major new facilities on the Hydro-Québec  
3       system” (Ibid. at 28). The Board found that the combination of the 323  
4       MW of expiring sales from Hydro Québec to Vermont, 3,500 MW of  
5       planned generation additions (including 2,510 under construction), and  
6       4,000 MW of planned efficiency programs would meet the HQ-VJO  
7       sale without new construction. (The order elaborates on some of these  
8       issues at 171–177.)
- 9       • “[I]t is reasonable to expect that Hydro Québec will attempt to sell the  
10      power elsewhere so that its projected export sales targets will be met  
11      and its construction schedule will not be delayed....it is also probable  
12      that over the longer term, even if the contract is rejected, Hydro Québec  
13      will continue to develop surplus hydroelectric capacity for sale to other  
14      utilities that could also be used to replace fossil fuel fired generation  
15      with similar air quality benefits.” (Order at 167–168, note 45).
- 16      • Of the three environmental scenarios that the DPS developed, the Board  
17      rejected the one in which one-third of the power displaced coal  
18      generation in Ontario, because of Mr. Winter’s testimony that Ontario’s  
19      dispatch of its oil plants would not be affected by purchases from Hydro  
20      Québec (Order at 167).<sup>39</sup> This was the only DPS scenario in which  
21      100% of the HQ-VJO energy was resold.

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<sup>39</sup>Mr. Winter actually testified that purchases from Hydro Québec might cause Ontario Hydro to reduce its coal-fired generation, and hence its carbon emissions, but not its production of acid gases (SO<sub>2</sub> and NO<sub>x</sub>), since HQ purchases would allow Ontario Hydro to defer retrofits or burn higher-sulfur coal. Alternatively, he testified, Ontario Hydro might reduce generation at its oil-fired units, or increase sales to other utilities, either of which would have effects similar to direct HQ sales into the Northeast US.

- 1       • If none of the HQ-VJO energy would be resold after a cancellation, the  
2       environmental benefits of the purchase were greater than if  $\frac{2}{3}$  of the  
3       energy were resold (Order at 167, finding 212.) The Board did not  
4       express an opinion about the amount of power that would be resold in  
5       the short term, but indicated that all of it would be resold in the longer  
6       term. (Order at footnote 45).
- 7       • The Department's scenarios in which less than 100% of the HQ-VJO  
8       power is resold assume that incremental hydroelectric development is  
9       delayed by the cancellation. (Order at 186–187, footnote 49)

10       The Board's conclusions on the environmental effect of the HQ-VJO  
11       contract are complex. On the one hand, the Board finds that the contract is  
12       “environmentally attractive” because large hydro is “less damaging than the  
13       alternative.” On the other hand, the Board finds that Hydro Québec's con-  
14       struction of large hydro is likely to be the same, with or without the contract.  
15       At least in the long term, the Board finds that Hydro Québec's off-system  
16       sales and resulting environmental effects would be the same with or without  
17       the contract. In the short term, the Board suggests that Hydro Québec might  
18       sell less energy off-system were the contract cancelled, but also suggests that  
19       the reduction in sales would only result from a delay in HQ's hydro  
20       construction schedule, which the Board does not believe will occur.<sup>40</sup> The  
21       Company did neither believe in 1991 nor believes today that cancellation of

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<sup>40</sup>Logically, the energy that would have been freed up in the short term by the cancellation of the HQ-VJO contract could have been used in other ways, such as filling the new reservoirs faster, which would provide more energy to be sold off-system in the long term, or reducing the operation of Hydro Québec's own high-sulfur oil plant. Each of these alternatives has environmental benefits.

1 the HQ-VJO contract would have changed Hydro Québec's expansion plans  
2 (IR DPS 8-17).

3 In short, the Order in Docket No. 5330 suggested that the environmental  
4 benefits of HQ-VJO contract are limited to the extent to which Hydro  
5 Québec would choose not to resell the energy if the contract were cancelled,  
6 and that whatever effects occurred would be limited to the short term. While  
7 the Board found the environmental effects of the purchase to be smaller than  
8 the environmental effects of alternatives, the differences must be rather  
9 small.

10 **Q: If Central Vermont had decided to extrapolate an environmental**  
11 **valuation of an HQ purchase from Board precedent, how might it have**  
12 **proceeded?**

13 A: The logical starting point for that extrapolation would be the 5% externality  
14 adder that the Board adopted for DSM in the order in Docket No. 5270.  
15 Unlike energy saved through DSM, which does not require the operation  
16 and/or construction of power plants, the energy (or the vast majority of it)  
17 from the HQ purchase results in the operation of fossil power plants. Those  
18 may be existing plants, including HQ's own Tracey oil plant, or plants that  
19 would otherwise be backed down in New England, New York, New  
20 Brunswick or adjacent areas, due to HQ's sales to other utilities.

21 Some of these plants would have higher emissions than the resources  
22 that would replace the HQ-VJO contract in CVPS's resource plan. Some of  
23 the additional generation due to the HQ-VJO contract, in the longer term,  
24 would be from new plants that have been, or will be, built in Québec or  
25 neighboring regions, but that would have been displaced had additional  
26 power been available from HQ's existing units. Only a delay in development



1 of new dams would lead HQ not to resell power. These dams “can have  
2 significant, negative environmental effects” and should not receive a zero  
3 environmental valuation. So the HQ adder that the CVPS might have tried to  
4 derive from the order in Docket No. 5270 would have to be substantially  
5 smaller than the 5% adder for DSM.

6 Depending on how one interprets the order in Docket No. 5330, it could  
7 be read as supporting a range of estimates of externality adders, from zero to  
8 perhaps 2% or so. For example, suppose the following:

- 9 • Two thirds of the HQ energy freed up by cancellation of the HQ-VJO  
10 contract would otherwise have backed down the same types of fossil  
11 resources that would have operated due to CVPS’s replacement of the  
12 HQ energy (so only one third is any cleaner than the replacement). At  
13 least this level of resales is implied by the discussion of the resale of  
14 Hydro Québec power in the Order in Docket No. 5330.
- 15 • The remaining third, which requires earlier installation of large hydro  
16 plants, has externalities per kWh that are a third of the externalities of  
17 CVPS’s replacements. The Order in Docket No. 5330 source suggests  
18 that hydro development has “significant, negative environmental  
19 effects,” but that these effects are “*less* damaging than the alternative  
20 supply sources.” For this example, I have assumed that significant, but  
21 less damaging, means something like one-third as damaging as the  
22 alternatives.

23 In this example, the HQ adder could be extrapolated from the DSM  
24 adder as the DSM adder times

1 [(the fraction of power that would have been resold) ×  
 2 (the benefit of using the power that would have been resold)] +  
 3 [(the fraction of power that would not have been resold) ×  
 4 (the benefit of deferring construction of HQ's large hydro)]  
 5 or  
 6  $5\% \times (\frac{2}{3} \times 0 + \frac{1}{3} \times \frac{2}{3}) = 1.1\%.$

7 **Q: Would an adder of this magnitude have affected a prudent utility's**  
 8 **decision as to whether to commit to the HQ-VJO contract (or a later**  
 9 **equivalent) or purchases from existing plants, followed by construction**  
 10 **of new gas-fired combined-cycle plants?**

11 A: No.

12 **Q: Did the HQ-VJO contract have significant benefits in reducing cost risks**  
 13 **to CVPS's ratepayers?**

14 A: No. While the contract had some advantages, it was a very large fixed  
 15 obligation, which added to CVPS's existing fixed obligations. The  
 16 independence of the HQ-VJO contract from fuel prices would have been  
 17 desirable to diversify the portfolio of a utility with primarily oil- and gas-  
 18 fired supply resources, but that description does not fit CVPS.

19 The Board's Order in Docket No. 6107 (at 47) recognizes that the HQ-  
 20 VJO contract does not have the characteristics for which the Board assigned  
 21 a risk credit to DSM.

22 **Q: Did CVPS understand the risks posed by the HQ contract and how to**  
 23 **deal with those risks?**

24 A: At least one senior manager understood this issue earlier in the HQ purchase  
 25 process. In a September 1988 document entitled "Key Assumptions:

1 Economics of Schedule C Analysis,” Bob Stein explained why CVPS should  
2 be careful to avoid excessive purchases from HQ (Exhibit DPS-PLC-19):

- 3 • Under a situation of uncertainty, CVPS should avoid making large long-  
4 term commitments unless the economics are highly favorable:

5           Uncertainty increases through time and flexible, balanced planning  
6 suggests that post 1995 commitments be made on a more  
7 conservative basis. Strong weight should be given to a low load  
8 growth, high NUG, high penetration of DSM scenario. Over the  
9 next few years we will learn much more about our needs for the  
10 mid 1990’s and beyond. While HQ now appears to be the most  
11 economic resource, over-commitment is expensive and embar-  
12 rassing.... Moral, *there’s always another train coming*. (emphasis  
13 added)

- 14 • “We should not plan on everlasting strong market for capacity.”
- 15 • “Cost should not be the only criterion.... We should consider splitting  
16 our eggs between HQ and resources with other price drivers.”
- 17 • “Like any good portfolio manager, we should divide our investments up  
18 and leave room for unknown future good deals. Undercommitting will  
19 also give us the future flexibility to see how our DSM efforts have  
20 fared and to understand where NUGs really are going. Lastly, under-  
21 committing will cause us to purchase capacity at whatever cost and  
22 would be defensible in a rate case whereas over-commitment would be  
23 at risk in rates.”

24           In early 1990s, CVPS should have been aware of these risks and avoided  
25 excessive commitment to this single source.

1 **IV. The Effectiveness of Central Vermont's Efforts to Mitigate the Costs of**  
2 **the HQ-VJO Contract**

3 **Q: Did CVPS achieve any mitigation of the HQ-VJO contract costs since the**  
4 **Board's Order in Dockets Nos. 5701 and 5724?**

5 A: No. Mr. Boyle's testimony in this case describes CVPS's efforts to reduce the  
6 costs of the contract, but acknowledges that those efforts were fruitless.

7 **Q: Then what are all the benefits that Mr. Boyle claims in his testimony?**

8 A: At page 81, Mr. Boyle claims savings from CVPS's four sellback  
9 arrangements with HQ.<sup>41</sup> These sellbacks occurred prior to Docket No. 5701,  
10 and hence are not the subject of this testimony.

11 At pages 82–85, Mr. Boyle reports on the difference between the costs  
12 of the HQ-VJO contract projected in 1990, and the actual costs to date and  
13 projected for the 2001/02 rate year. These savings are due to lower inflation  
14 rates and costs of capital, rather than CVPS's skill in negotiation.

15 **Q: Are these cost reductions reflected in your analysis?**

16 A: Yes. I use the actual and projected costs of the HQ-VJO project in the  
17 relevant test years.

18 **Q: Does it matter whether CVPS's unsuccessful efforts were undertaken**  
19 **prudently?**

20 A: No. In Docket No. 5701, the Board offered CVPS the opportunity to reduce  
21 the penalty by demonstrating, "through tangible results, that it has eliminated  
22 the excessive power costs imposed on customers by ineffective and

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<sup>41</sup>He acknowledges that those benefits will be offset to some extent by costs that are not fully estimated.

1 improvident management decisions, or that it is on a reasonable and  
2 equitable path towards doing so” (Order at 172). Mr. Boyle’s testimony does  
3 not make either of these demonstrations.

4 How hard CVPS tried to negotiate a better deal with HQ is not relevant  
5 to this docket. Even assuming that CVPS has done nothing else wrong since  
6 1994, the costs of its prior imprudence have increased and the probability of  
7 CVPS being able to correct the problem has decreased.

#### 8 **V. Excess Rate-Year Costs of the HQ-VJO Contract**

9 **Q: How much would CVPS have paid to replacing the HQ-VJO contract in**  
10 **the Docket-No.-6120 rate year had CVPS prudently managed its power**  
11 **supply in the early 1990s?**

12 **A:** Depending on the exact mix of base, intermediate, and peaking resources; the  
13 duration of each contracts; and the details of contract pricing that CVPS could  
14 have negotiated, prices of individual contracts in 1999 would have been  
15 between 3¢/kWh and 5¢/kWh.

16 As enumerated in Exhibit DPS-PLC-20,

- 17 • Until’s purchases that that resulted from its 1991 RFP cost  
18 \$41.90/MWh.
- 19 • The NU offers to CVPS would have cost about \$40/MWh for either the  
20 Montville-Middletown Oil Block or system power.
- 21 • Offer A from NYSEG would have cost \$49/MWh.

- 1       • The municipal utilities for which we have actual 1999 prices paid \$40–  
2       54/MWh under their early-1990s market-based contracts.<sup>42</sup> The  
3       contracts for which I can backcast prices (adjusted for the Newbay  
4       charges), all cluster around \$40/MWh.
- 5       • Burlington’s purchases from NU and NYSEG cost about \$33/MWh and  
6       \$37/MWh, respectively.
- 7       • The New Hampshire Electric Coop’s contract with CVPS cost  
8       \$27/MWh.

9   **Q: How do those prices compare to what Central Vermont paid for HQ**  
10 **power in 1999?**

11 A: Central Vermont’s spreadsheet HQ\_HIST.wk4 indicates that purchases under  
12 the contract in 1999 averaged \$58.3/MWh, for a total cost of \$53.5 million  
13 for 917 GWh.<sup>43</sup>

14 **Q: What portion of the 1999 power cost was due to CVPS’s imprudence?**

15 A: had CVPS paid an average of \$40/MWh (a mid-range price for the purchases I  
16 list above), it would have been paying 31%, or \$16.8 million, less than the  
17 actual cost of the HQ-VJO contract.

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<sup>42</sup>This range excludes the sale from NEPCo to Littleton, which includes an undetermined amount of Newbay buyout charges in 1991, and brings the NEPCo-Reading sale up to 75% capacity factor using the contract energy price. Other than these two contracts and the requirements contracts, the highest price was \$44/MWh.

<sup>43</sup>These values are consistent with the net purchases and sales reported in Central Vermont’s 1999 FERC Form 1, pp. 310 and 326. Central Vermont reports higher prices and lower energy purchases in HQ\_sav\_90\_vs\_01.wk4, the workpapers for Mr. Boyle’s Exhibit FJB-30.

1   **Q: How would Central Vermont have paid for replacing the HQ-VJO**  
2       **contract in the Docket No. 6460 rate year if CVPS had prudently**  
3       **managed its power supply in the early 1990s?**

4   A: From the same exhibits, using CVPS's projection of near-term oil prices, I  
5       project that prices in 2001/02 would have been between 3¢/kWh and  
6       5.7¢/kWh.

7       As shown in Exhibit DPS-PLC-21, for the 2001/02 rate year,

- 8       • The NU offers to CVPS would cost \$54/MWh for the Montville-  
9       Middletown Oil Block and \$52/MWh for system power. Central  
10      Vermont would have replaced some of the expensive energy in the Oil  
11      Block with off-peak energy purchases.
- 12     • Offer A from NYSEG to CVPS would have cost \$54/MWh.
- 13     • The municipal-utility power-supply contracts for which I can project a  
14      price for 2001/02 will cost \$42–57/MWh.
- 15     • Burlington's purchases from NU and NYSEG will cost about \$39/MWh  
16      and \$41/MWh, respectively.
- 17     • The take-or-pay portion of NHEC's contract with CVPS will cost about  
18      \$25/MWh. Supplementing the contract with CVPS's incremental energy  
19      to bring it to a 75% capacity factor would raise the price to about  
20      \$29/MWh.<sup>44</sup>

21   **Q: How do those prices compare to what Central Vermont will be paying**  
22       **for power under the HQ-VJO contract in the rate year?**

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<sup>44</sup>Generally, a higher capacity factor resource would have a lower price. This situation is reversed for the CVPS-NHEC contract in 2001/02, partly due to the increase in fuel prices since the contract was signed.

1 A: Central Vermont projects that it will be paying \$63.89/MWh in 2001 and  
2 \$64.54 in 2002, for an average rate-year cost of \$64.21/MWh and a total cost  
3 of \$60.2 million for 938 GWh.<sup>45</sup>

4 **Q: What portion of the cost was due to CVPS's imprudence?**

5 A: If the average cost of CVPS's alternative portfolio was \$45/MWh (again, in  
6 the middle of the range), the Company would be paying 30%, or \$18 million,  
7 less than for the HQ-VJO contract.

8 **Q: Are the costs of imprudence that you have estimated the same as the**  
9 **uneconomic costs estimated by Mr. Biewald?**

10 A: No. Mr. Biewald's testimony concerns the long-run economic usefulness of  
11 the HQ-VJO contract using today's information about the rate year and  
12 beyond. My analysis is concerned with what CVPS would be paying if it had  
13 been prudent in 1991–1995, while Mr. Biewald's analysis is concerned with  
14 what CVPS would pay if it were to replace the HQ-VJO contract on a  
15 forward-going basis, at current expectations. Mr. Biewald therefore compares  
16 the cost of the contract to a current market-price forecast, appropriately  
17 including actual NEPOOL market-clearing prices for 1999 and current prices  
18 for power to be delivered in 2001 and 2002. The prices he reports for those  
19 years are different from the costs of resources that CVPS could have acquired  
20 in the early 1990s.

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<sup>45</sup>These values are from Central Vermont's spreadsheet HQ\_FORC.wk4. For comparison, Mr. Boyle's Exhibit FJB-1 projects an average cost of \$63.86/MWh for the twelve months ended 10/31/01, and the workpapers for that Exhibit project \$64.50/MWh for the year ending 10/31/02. The rate year includes four months from the year ending 10/31/01 and eight months from the year ending 10/31/02, for an average cost of \$64.29/MWh, which agrees well with the \$64.21/MWh I quote in the text.



1           Actual market prices were very low in 1999, and many prudent  
2           contracts from the early 1990s exceeded the market price in 1999. Hence, the  
3           uneconomic portion of the contract cost in 1999 was larger than the  
4           imprudent portion. For 2001/02, the situation is reversed; market prices are  
5           expected to be higher than the costs of prudent contracts signed in 1991–95,  
6           so the uneconomic portion of the contract is less than the imprudent portion.

7   **Q: Are these excess costs in the rate year likely to be offset by benefits in**  
8   **later years?**

9   A: No. Mr. Biewald reviews the projected costs of the HQ-VJO contract in his  
10   testimony.

11   **Q: Does this conclude your testimony?**

12   A: Yes.